

NON-PUBLIC?: N  
ACCESSION #: 9106120105  
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Millstone Nuclear Power Station Unit 3 PAGE: 1 OF 06

DOCKET NUMBER: 05000423

TITLE: Manual Reactor Trip Due to Moisture Separator Reheater Piping  
Line Breaks

EVENT DATE: 12/31/90 LER #: 90-030-02 REPORT DATE: 06/06/91

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 86

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR  
SECTION:

50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:

NAME: Terry McNatt, Engineer, Ext. 5592 TELEPHONE: (203) 447-1791

COMPONENT FAILURE DESCRIPTION:

CAUSE: SYSTEM: COMPONENT: MANUFACTURER:

REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On December 31, 1990, at 1636 hours with the plant in Mode 1 at 86% power, 580 degrees Fahrenheit and 2250 psia, a manual reactor trip was initiated due to two 6-inch Moisture Separator Drain line (DSM) piping breaks in the Turbine Building. Following the trip a Main Steam Line Isolation was initiated to minimize the release of steam into the Turbine Building.

The root cause of the event was the failure to enter the affected lines into the computer analysis program that was utilized to determine piping susceptible to erosion/corrosion. The omission from the erosion/corrosion monitoring program resulted in the DSM piping not being inspected prior to the failure downstream of the two level control valves. The wall thickness at the rupture was approximately 0.020 inches. The cause of the severe wall loss was single phase erosion/corrosion. The combination of temperature, high fluid velocity

and extremely low oxygen content are the causative factors. The wall loss was localized.

As immediate corrective action, control room operators performed the actions required by the applicable emergency operating procedures. The ruptured pipes were capped and the DSM pumps and piping were isolated to allow continued operation.

During the third refueling outage, which began on February 2, 1991, the piping upstream and downstream of the level control valves was replaced with piping having greater erosion/corrosion resistant properties.

END OF ABSTRACT

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## I. Description of Event

On December 31, 1990, at 1636 hours with the plant in Mode 1 at 86% power, 580 degrees Fahrenheit and 2250 psia, a manual reactor trip was initiated due to two six inch Moisture Separator Reheater drain line (DSM) piping breaks in the Turbine Building. Following the trip a Main Steam Line Isolation was initiated to minimize the release of steam into the Turbine Building. Breaks occurred in lines downstream of the respective level control valves 3DSM-LV20A1 and B1, due to severe wall thinning caused by erosion/corrosion (refer to Figure 2). The piping failure resulted in the release of approximately 127,000 gallons of steam/water from the condensate piping and hotwell and 65,000 gallons of water from the condensate surge tank. The thermal energy of the fluid released from the ruptured piping activated the fire protection sprinkler system releasing an additional 25,000 gallons of water into the Turbine Building. In addition to mechanical and electrical damage in the Turbine Building, a power loss caused the isolation of instrument air to the containment, resulting in the loss of normal pressurizer spray flow and the isolation of normal letdown flow. Reactor Coolant Pump Seal Injection was reduced to the minimum allowable. Pressurizer level and pressure increased. One Power Operated Relief Valve (PORV) lifted three times to control reactor coolant system pressure.

At the time of the trip, operators verified that the reactor trip and bypass breakers were open, that all control rods were fully inserted, and that neutron flux was decreasing. An Auxiliary Feedwater actuation occurred as a result of steam generator low-low level signals. This is a normal plant response following a trip

from 86% power. A Main Steam Line Isolation was manually initiated due to the line break in the Turbine Building. No additional engineered safety features were required or initiated. There was no operational, maintenance, or construction activities in progress at the time which affected the event. The plant stabilized at approximately 1841 hours based on stable reactor coolant system temperatures, the restoration of normal letdown flow, and restoration of normal pressurizer pressure control.

## II. Cause of Event

The cause of the failure of the DSM lines was severe wall thinning downstream of the control valves. The wall thickness of the carbon steel, six inch, schedule 40 pipe had decreased from a nominal thickness of 0.280 inches to 0.020 inches at the failure sites. The cause of the thinning is attributed to single phase erosion/corrosion. Piping design, fluid temperature, high fluid velocity, and oxygen content of the fluid contributed to the accelerated wear rate. The original piping design in the early 70's had not considered the significant reductions in fluid oxygen levels that would be achieved by the time the unit was ready for operation. The minimum thickness occurred adjacent to the control valve(s), and increased by 0.011 inches per inch downstream from the valve(s).

The configuration of the failed piping was a horizontal run of 10" piping which reduced to 6" piping upstream of a 6" control valve. The 6" piping extended up to a 6" manual isolation valve, then expanded to 10" piping, before tying into the Condensate System. While it is normal to reduce the line size of piping directly upstream of a control valve, in typical piping designs, the piping is increased to the original line size immediately downstream of the associated control valve (see Figure 2). The fluid velocity in the piping downstream of the control valves has been calculated to be in the range of 17 ft/sec. which when coupled with the low oxygen levels produces a high erosion rate.

The root cause of the event was the failure to enter the affected lines into the computer analysis program (CHEC) that was utilized to determine piping susceptible to the erosion/corrosion. The DSM lines were not entered due to the misinterpretation of a note on the input data sheet. A contributing factor was misunderstanding as to who had the overall responsibility for the program. The erosion/corrosion monitoring and inspection program for these non-safety related piping systems was developed and has been in use following the failure of non-safety related piping at Surry in 1986. NRC Notice 86-106, Generic Letter 89-08 and other documents aided in

this development by providing information regarding computer programs such as the EPRI CHEC program to predict piping areas susceptible to single phase erosion/corrosion and the developmental MIT program. The data entry error resulted in the DSM system piping not being entered into the computer program. A comprehensive review has determined that no other piping was omitted.

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### III. Analysis of Event

This event is being reported in accordance with 10CFR50.73(a)(2)(iv) as an event or condition that resulted in manual or automatic actuation of an Engineered Safety Feature, including the Reactor Protection System. An immediate notification was made in accordance with 10CFR50.72(b)(2)(ii).

There were no significant safety consequences due to this event. The loss of instrument air to Containment resulted in a loss of normal non-safety related pressurizer pressure and level control. As a result, pressurizer pressure increased to the PORV setpoint. The PORV's functioned as designed to prevent pressure increases beyond the PORV setpoint. The safety grade letdown flowpath was available, but it was not used because restoration of the normal flowpath was expected. After the PORV cycled the second time, both the valve open and valve closed lights on the main control boards remained illuminated. PORV discharge tailpiece temperature was used to verify the PORV had reseated. The loss of power in the Turbine Building led to a loss of power to the plant process computer, rendering the Safety Parameter Display System (SPDS) unavailable. Control Room operators used the backup status trees to verify critical status functions. Monitoring functions normally performed by the computer were performed manually until power was restored to the computer.

### IV. Corrective Action

The damaged sections of pipe were removed. Temporary pipe caps of a material consistent with the original system design were installed. The plant returned to power utilizing the Moisture Separator drain system alternate drain lines. (See Figure 1). During the third refueling outage (RFO3), which began on February 2, 1991, the six-inch diameter piping unstream and downstream of the level control valves was replaced with six-inch piping having greater erosion/corrosion resistant properties (i.e., 5% chrome-moly,

schedule 40 pipe (A-335, grade P5)). The existing piping configuration was determined to be acceptable with the change in piping material.

The erosion/corrosion program was reviewed to verify that no other systems or portions of systems were omitted from the erosion/corrosion analysis. The affected DSM lines were added to the inspection program. These lines will remain in the inspection program even though they would be exempted because of the high chrome content of the replacement piping. Prior to the restart of the plant following the pipe break, nondestructive examinations were performed on the remaining sections of piping, on welds upstream and downstream of the failed piping, on a representative sample of piping with similar configurations, and downstream of the alternate drain line control valves. The DSM piping downstream of the alternate drain line control valves was inspected again during the refueling outage. The remaining piping systems with similar configurations were inspected during the refueling outage.

The complete erosion/corrosion program was remodeled using the CHECMATE program. The CHECMATE inspection output was analyzed to identify any piping that required inspection prior to returning to service following the refueling outage. A total of 164 erosion/corrosion examinations were performed prior to and during RFO3. Three piping lines were identified as requiring repairs in addition to the original DSM piping. All repairs have been completed. In addition, three piping lines were identified as requiring monitoring during the operating cycle (i.e., Cycle 4).

The instrument air containment isolation valve control circuitry was modified to prevent valve isolation on a loss of power to the current-to-pneumatic (I/P) controller.

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An engineering task force was formed to investigate the root cause and to provide corrective action recommendations. The task force report was issued on March 27, 1991. The task force recommendations have been reviewed and two additional factors were identified. At the time the error was made, there was misunderstanding about who had the responsibility for the erosion/corrosion program. The Engineering Department of the recently restructured Nuclear Engineering and Operations (NEO) organization has been assigned the responsibility for the development, review, and coordination of the erosion/corrosion program. The less than adequate communication, documentation, and transmittal of data contributed to the

misinterpretation of the note on the data entry sheet resulting in the input error. NEO will implement an erosion/corrosion program guideline by March 31, 1992, to address the process for data input, the format for data transmittal, and the review of input data to minimize the misinterpretation of input data.

#### V. Additional Information

There have been no similar events that have occurred at Millstone 3.

#### EIIS Codes

##### System Component

Main Steam Reheat System-SB Level Control Valves-LCV

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Figure 1 "DSM Piping Configuration" omitted.

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Figure 2 "DSM vs. Typical Piping Configuration" omitted.

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#### NORTHEAST UTILITIES

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Northeast Utilities Service Company  
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Re: 10CFR50.73(a)(2)(iv)

June 6, 1991

MP-91-471

U.S. Nuclear Regulatory Commission  
Document Control Desk  
Washington, D.C. 20555

Reference: Facility Operating License No. NPF-49  
Docket No. 50-423  
Licensee Event Report 90-030-02

Gentlemen:

This letter forwards Licensee Event Report 90-030-02 which is being submitted as an update report by June 7, 1991, in accordance with LER 90-030-01. Licensee Event Report 90-030-00 was submitted pursuant to 10CFR50.73(a)(2)(iv), any event or condition that resulted in manual actuation of any Engineered Safety Feature (ESF), including the Reactor Protection System (RPS).

Very truly yours,

NORTHEAST NUCLEAR ENERGY COMPANY

Stephen E. Scace  
Director, Millstone Station

SES/TGM:ljs

Attachment: LER 90-030-02

cc: T. T. Martin, Region I Administrator  
W. J. Raymond, Senior Resident Inspector, Millstone Unit Nos. 1, 2  
and 3  
D. H. Jaffe, NRC Project Manager, Millstone Unit Nos. 1 and 3

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